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California Shorts a Circuit

Should Canadians Trust the Wiring Diagram?

Mark Jaccard

In this issue...

California's electricity crisis has shaken the worldwide electricity reform movement, but cautious, carefully designed reform should continue.

The Study in Brief

California's crisis in 2000-01 shook the worldwide electricity reform movement, intensifying debate on the merits of competitive generation markets.

Competition advocates argue that design errors by California's reformers caused the crisis. One mishap, in contrast with reform successes elsewhere, does not justify forgoing the consumer benefits from improving operating efficiency and sharing investment risk with private producers. Smaller, competing electricity suppliers are the future, replacing monopolies that never understood the full risks inherent in megaprojects such as nuclear plants.

According to skeptics, however, California's experience proves that electricity's unique characteristics thwart competition, so efforts at market restructuring will ultimately hurt consumers. Electricity is essential to modern economies, and it cannot be stored; demand and supply must always be precisely equal everywhere on the grid. These special conditions mean that the cyclical pattern of commodity markets will be exaggerated in the electricity sector, leading to California-like extremes of supply shortages, skyrocketing prices, profiteering, and costly blackouts.

What is the lesson from California? Should Canadian jurisdictions abandon the reform trend, even reversing it in Alberta and Ontario?

The answer is no. Competitive electricity markets are achievable, and the potential social benefit is enormous given the risks facing electricity investments today.

California's calamity shows, however, the large risks from market design mistakes. Reformers must create incentives to ensure that the market has an adequate capacity reserve and that some consumers will quickly reduce their demand when markets tighten. The system operator should have effective means to acquire supplies on short notice. Long-term supply contracts should protect most of the consumer bill from short-run price fluctuations.

The reform movement should continue. But reforming jurisdictions need to be more cautious and more cognizant of electricity's uniqueness when designing competitive markets.

The Author of This Issue

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Just a few years ago, electricity market reform appeared unstoppable, destined to transform the worldwide electricity sector into a competitive, efficient, and customer-responsive industry. Countries and jurisdictions around the world established study groups and implementation task forces to work out the details of a greater role for private competition in a sector that was traditionally characterized by publicly owned monopolies. Even Canada, with its long tradition of Crown electricity monopolies, has been drawn in, as Alberta and now Ontario push ahead with dramatic electricity sector reforms while other Canadian provinces debate their next steps.[1]

England is proud of its leadership role. Early reform success at the beginning of the 1990s positioned that country's experts as leading emissaries of the international electricity reform movement. Soon, other jurisdictions converted with varying degrees of caution and daring. Then, in 1996, California announced it would go further and faster than any had before by opening its reformed electricity market to all consumers, big and small, on the same day.

That day came in April 1998. Aside from a few glitches, the transformation unfolded as planned, and for the next two years the market operated smoothly. But in summer 2000, the system short-circuited as prices gyrated and then skyrocketed out of control. For close to a year, California found itself scrambling and sometimes failing to meet peak demand even when paying astronomical prices to suppliers. After a period of denial, politicians tried to control wholesale prices, worsening the situation. The state's investor-owned utilities unwillingly retailed electricity at regulated rates far below their wholesale acquisition costs, precipitating a financial crisis for these utilities, one that has since spilled over to the state government itself. Wholesale prices in California finally ebbed by mid-2001, but while lawyers and regulators sort through the debris, the state's electricity system remains particularly vulnerable to unforeseen combinations of extreme weather, demand shifts, and generator shutdowns.

Neighboring jurisdictions, even as distant as Canada, whirl in California's maelstrom. After apparently reaping windfall profits from exports to California, BC Hydro is now under investigation by US regulators for price gouging. With unfortunate timing, Alberta auctioned off the generation rights to its low-cost coal plants just before the jump in region-wide wholesale prices caused by California's electricity and natural gas demand. Most of its consumers are not pleased with the loss of their stable low rates. Ontario is caught in the midst of dramatic reforms, unsure whether its current path will also lead to a crisis.

Indeed, California's crisis has stunned the worldwide electricity reform movement, as experts, politicians, and interest groups now investigate the state's reform wiring diagram, trying to understand what caused the short circuit and what can prevent similar mishaps in their jurisdictions. The importance of electricity to modern

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1 The terms *reform* or *restructuring*, instead of *deregulation*, avoid the unhelpful debate over whether increased or decreased regulation is the ultimate goal or outcome. If the objective is to improve how the electricity sector meets society's needs, whether the jurisdiction increases or decreases regulation is immaterial. Its measurement is controversial in any case.

society complicates this undertaking, as opposing ideologues stake out their ground. For those who favor a state-dominated, centrally planned electricity sector, California's debacle vindicates their skepticism, reinforcing their conviction about the special character of electricity and the consequent need for central planning and public ownership. For believers in unfettered markets, the flawed design of California's timid reformers did not give markets a chance; politicians and regulators only exacerbated the crisis by trying to control prices.

Consumers and politicians do not know whom to believe — yet decisions have to be made. Some jurisdictions are in the middle of reform. Others are about to begin. Even in England, analysts wonder if recent modifications now leave their system vulnerable to a California-style failure. Canadian provincial governments ponder what to do next.

In this *Commentary*, I seek to provide Canadians with a better understanding of the pros and cons of electricity market reform. First, I explain the rationale for the move toward competitive generation markets. Advocates of reform see competitive markets as an effective means of achieving economic efficiency and allocating the risks of investment uncertainty. (The electricity sector is noteworthy for large investment uncertainty.) I summarize the developments in England as an example of successful reform. Then I describe California's misadventure. This crisis provides compelling evidence for a cautious approach to reform, one that builds in safeguards and robustness to a wide variation in difficult-to-control factors while allowing market forces the chance to perform effectively.

Indeed, California's experience illustrates the importance of understanding and addressing two facets of electricity's uniqueness: its essential, unsubstitutable role in the economy and its physical requirement that supply and demand be balanced instantaneously at all times throughout the delivery network. These attributes create special challenges and thus favor particular design characteristics for the development and stable operation of competitive electricity markets.

I follow this general discussion with a survey of the current status and experiences of the reform movement in Canada, and I conclude with some suggestions for Canadian policymakers.

A Primer on Electricity Market Reform

Today's reform of the electricity market is driven primarily by technological, economic, and regulatory changes in the industry's generation component.

For most of the twentieth century, monopolies have dominated the electricity industry. Apparent economies of scale led most jurisdictions to establish vertically integrated monopolies responsible for generation, transmission, and distribution. In the interests of prudent investment, efficient operation, and fair pricing, these monopolies were either publicly owned or privately owned but regulated by an independent agency, usually a utilities commission.

Today's reform of the electricity market is driven primarily by technological, economic, and regulatory changes in the industry's generation component. A decrease in the relative costs and risks of smaller generation plants has undermined the justification for continued reliance on a few large plants owned and operated by monopolies. The reasons are several (Hansen 1998). First, the evolution of the

combined-cycle gas turbine[2] has resulted in efficiency gains and capital cost decreases that, if combined with moderate natural gas prices, make this technology — even in small units of only a few megawatts — competitive with large conventional facilities. Less conventional, small-scale technologies, such as wind turbines, have also undergone substantial cost decreases, making them competitive in certain locations. Second, the costs of large-scale, conventional generation technologies have risen as a result of increasingly stringent approval processes and operating regulations for nuclear facilities, large hydro plants, and fossil fuel plants. Also, operating costs and capital requirements have sometimes proven higher than anticipated for technical reasons; an example is Ontario's experience with the construction and operating costs of its nuclear power plants. Third, steady and rapid growth in electricity consumption in the three decades after World War II masked the substantial risks associated with building large generation plants whose construction requires long lead times. The dramatic downturn in electricity demand in the early 1980s caused enormous financial losses, especially in the United States, where electricity monopolies were forced to cancel many half-completed megaprojects. This experience alerted policymakers to the risk that such projects pose for bondholders, consumers, and taxpayers, a risk that private investors in competitive markets had long been familiar with (Pindyck 1991).

The change in costs and risk awareness has convinced many economists that although monopoly may still be the best industry structure for transmission and distribution it should be replaced by competition in generation (Brennan et al. 1996; Hunt and Shuttleworth 1996; Joskow 1998). Fostering competition among many large and small electricity generation companies — if combined with open access to the transmission and distribution network — should bring the usual benefits of lower long-run prices. Consumers can switch their purchases from high-cost to low-cost generators, whereas they cannot in a monopoly world. If their monopoly misinvests — say, in nuclear power — consumers must pay (or perhaps taxpayers if the monopoly is publicly owned). In the competitive world, investors pay for their misfortune. Consumers do not escape unscathed, but after a transition period (whose duration depends on the length of their contractual commitment), they can switch their business to the emerging low-cost suppliers.

Electricity markets are, and will continue to be, highly uncertain.

Electricity markets are, and will continue to be, highly uncertain. Imbalances of supply and demand — and hence price instability — are unlikely to diminish, given that demand is linked to shifts in economic activity and that both demand and supply are sensitive to weather conditions (which affect, for example, air-conditioning loads and the availability of hydro power). Moreover, environmental harm from fossil fuel combustion (air pollution, greenhouse gases) and public perceptions of the environmental impacts and the risks of nuclear and hydro power exacerbate the uncertainties about future regulations, technological change, and costs. The only certainty is that misinvestments in electricity generation — some of them colossal — will continue to occur, resulting in the typical market mix of winners and losers. In this situation, it is prudent for society to encourage private

2 A combined-cycle gas turbine uses the exhaust gases of a turbine to turn a generator directly and to heat water into steam that turns a second generator. These two processes explain the term *combined-cycle*. Although the turbine could burn various fuels, natural gas is the dominant energy source.

investors to assume a significant share of the risk, leading to lower average costs for consumers in the long run.

The Example in England

The essentially economic rationale described above has supported policy reform toward a competitive market for electricity generation, but other factors have also played a role. In the late 1980s and early 1990s, Margaret Thatcher's government in the United Kingdom aggressively pursued increased private participation throughout the economy, and electricity was simply one of several candidate sectors. This ideological motive provided reformers with considerable latitude to make changes so fundamental that the industry transformation in England and Wales is frequently cited as the most comprehensive illustration of electricity market reform (Newbery 1999).[3]

Over a three-year implementation period (1989 through 1991), England's state-owned electricity monopoly was privatized and broken up vertically and horizontally. Generation, which was separated from transmission and distribution, was split into two large private companies with the nuclear units remaining in public ownership (some have since been privatized). Twelve private distribution companies were established, each with a distribution monopoly in its geographic area and each regulated by a newly created utility regulator. To increase competition in generation, these distribution companies are allowed to self-generate up to 15 percent of their customers' electricity demand. Mostly, the result has been the development of small, affiliated generation companies. Ownership of the transmission entity was dispersed among the 12 distribution companies and other private investors to ensure its independence from the generation companies; it is also under the control of the utility regulator. An independent system operator, with responsibility to ensure cost-minimizing market operation, including the provision of system support services, operated a power pool (which was mandatory until 2001) for matching supply and demand. Prices in electricity generation are deregulated, the outcome of supply and demand interaction in the power pool and in separate financial contracts. The independent regulator applies a hands-off, price-cap method to regulate the transmission and distribution monopolies and the threat of antitrust complaint to discourage price manipulation in the generation market.

To the surprise of skeptics, the English reforms unfolded smoothly. Electricity prices fell by 30 percent in real terms through the 1990s.

To the surprise of skeptics, the English reforms unfolded smoothly. Electricity prices fell by 30 percent in real terms through the 1990s. New capacity investments were substantial, especially as plants fired by natural gas replaced coal-fired plants. The coal-mining industry had significant job losses, but many of the mines had been uneconomic for some time, surviving only because of the above-market, politically determined coal prices paid by the former electricity monopoly. Reliability was not compromised, and some aspects of customer service, such as response time to complaints, improved substantially.

Despite ongoing debates about fine-tuning the market, reverting to the old system is an idea that finds no support. The most significant adjustment in a decade

3 In the description below I refer only to England for convenience, although my comments apply equally to Wales but not to Scotland or Northern Ireland.

was the replacement in 2001 of the mandatory power pool with voluntary trading arrangements (Green 1999).

The Spread of Reform

The reforms in England and elsewhere piqued the interest of those who believe that markets generally outperform central planning in allocating society's resources. Countries as diverse and distant as Norway, Chile, New Zealand, and Argentina were early adopters of electricity sector reform in various guises for various reasons, and the movement quickly spread worldwide. Jurisdictions with relatively high electricity prices have been especially interested (International Energy Agency 2001).

California's Electricity Reform

By the early 1990s, California's electricity prices were 50 percent higher than the US average.

By the early 1990s, California's electricity prices were 50 percent higher than the US average, about 11 cents per kilowatt hour (kWh) for residential customers.[4] California had a legalistic regulatory process with layers of detailed procedures and public hearings for assessing resource investment options, implementing energy efficiency programs, and setting rates. In 1994, the California Public Utilities Commission (CPUC) issued a reform proposal that expressed its intention of following England's lead, thereby launching a nationwide debate on the specifics of electricity-sector reform (CPUC 1994). In 1996, the CPUC issued its restructuring decision (Decision 95-12-063 and Decision 96-01-009) and the California legislature passed a law (Bill 1890) that set early 1998 for the transformation to a competitive electricity market, giving suppliers direct access to all retail customers.

California was one of the leaders in US electricity reform, but it did not act alone. Today, almost every US state is somewhere along the reform path, 24 having enacted significant reform legislation by mid-2001 (see Figure 1). Reform has also occurred in Alberta and is under way in Ontario. Indeed, with substantial changes in 1996, Alberta was the first jurisdiction in North America to significantly restructure its electric sector along competitive lines.

A critical requirement for jurisdictions pursuing competitive electricity markets is that customers have access to as many electricity providers as physically possible. In the United States, the *National Energy Policy Act of 1992* and subsequent reforms by the US Federal Energy Regulatory Commission (FERC) played a critical role in achieving this diversity. In 1996, the FERC ordered (Order 888 and Order 889) all holders of transmission facilities to provide cost-based tariffs and open access to anyone wishing to transmit wholesale power on their grids. Systems with significant interconnections were encouraged to create regional organizations with common rules of access and tariff principles.[5] This policy alone has had a substantial efficiency effect on the US electricity system as wholesale traders exploit synergies in the production capabilities and demand patterns of interconnected jurisdictions.

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4 When referring to California, this paper gives prices in nominal US dollars. In the discussion of Canadian jurisdictions in a later section, the prices are in nominal Canadian dollars.

5 The policy was reinforced in 1999 by FERC Order 2000, which pushes for the establishment of regional transmission organizations.

Before reform, the California electricity industry was dominated by three large, vertically integrated, investor-owned utilities: San Diego Gas and Electric, Southern California Edison (Los Angeles), and Pacific Gas and Electric (San Francisco). California represents 10 percent of the US market with average annual consumption of 250,000 gigawatt hours (GWh) in the 1990s.[6] California-dedicated electricity generation capacity, in and outside the state, is about 50,000 megawatts (MW). The fuel sources include natural gas (32 percent), large hydro (20 percent), coal (20 percent), nuclear energy (16 percent), and renewables (12 percent).[7] During peak-demand periods in the past few years, the state has relied on up to 10,000 MW of imports from neighboring states as well as Canada and Mexico. Authority over the electricity market resides with the state's legislature, but it delegates responsibility for utility regulation to the CPUC. Because interstate and wholesale electricity trade is regulated federally by the FERC, any changes involve coordination of state legislation with CPUC directives and FERC policies.

California's reform included the establishment of an Independent System Operator, a nonprofit corporation, to plan, operate, and set tariffs for the state's transmission system.

California's reform comprised establishing the following key components.[8]

- A Power Exchange (PX), a nonprofit corporation, regulated by the FERC, to provide an open, nondiscriminatory power pool (spot market) for electricity sellers. Participation in the PX was voluntary for all market participants except the major investor-owned utilities, which were required to use it for scheduling all day-ahead demand for their default customers and all supply from their remaining generation facilities.
- An Independent System Operator (ISO), a nonprofit corporation, regulated by the FERC, to plan, operate, and set tariffs for the state's transmission system. The utilities retained ownership but not control of transmission facilities and had full ownership and control of their distribution facilities. In order to balance supply and demand in real time at all points on the grid, the ISO aggregated the hourly demand requirements from independent and utility schedulers and then accepted supply bids on a day-ahead and an hour-ahead basis from electricity providers. The PX provided aggregate supply and demand bids from its market, and these were combined with other bids by the ISO. The ISO also ran a market to acquire from generators operating ancillary services, such as spinning reserves and emergency backups. Generators selected to provide such services were paid a reservation price to hold capacity in reserve; they were also paid for any energy they were called on to provide on short notice.

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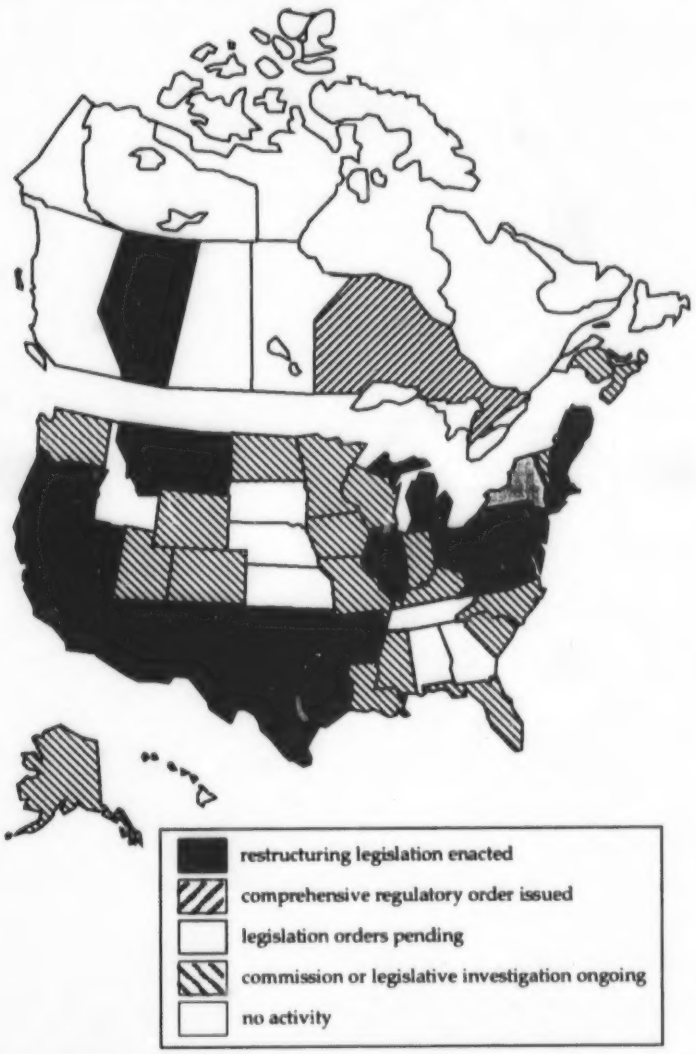
6 Although the population of California is similar to that of Canada, its electricity consumption is only about 50 percent of the Canadian total. Relatively low-cost hydro power and fossil fuel resources have played a key role in the development of electricity-intensive industry in Canada.

7 Readers should be wary of electricity capacity statistics for California. They vary depending on whether or not the analyst includes: (a) out-of-state plants that are dedicated to California (all coal plants for example), (b) capacity owned by municipal utilities, and (c) industrial and other co-generation capacity. The approximate number of 50,000 megawatts given in the text includes (a), (b), and some of (c).

8 This description of the California reform, crisis, and subsequent developments is primarily based on regularly updated information on the websites of the US FERC (www.ferc.fed.us), the US Energy Information Administration (www.eia.doe.gov), the CPUC (www.cpuc.ca.gov), the California Independent System Operator (www.caiso.com), and the California Power Exchange (www.calpx.com). See also Sioshansi (2001); Joskow (2001); and Faruqui et al. (2001).

Figure 1: ***Status of Electricity Restructuring in the United States and Canada, August 2001***



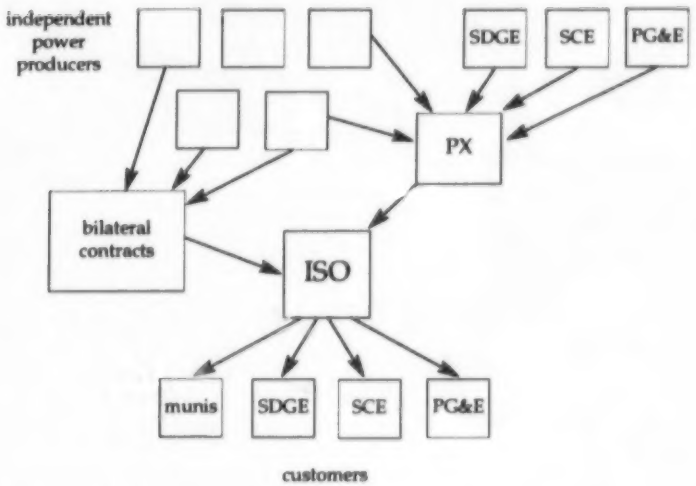
Sources: US information from the Energy Information Administration, "Status of State Electric Industry Restructuring Activity," available from Internet website: www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html; Canadian information from author's files.

- An Oversight Board to monitor and hear appeals against the ISO and PX.
- The Competitive Transition Charge imposed on all utility consumers, to compensate the major utility shareholders for historic cost obligations — nuclear plants, long-term independent supply contracts — that would otherwise be unrecoverable ("stranded") under competitive markets. The charge was not a fixed amount but depended on the difference between the utilities' wholesale acquisition costs in the PX and their retail rates. After 2002, remaining unrecovered costs would become shareholder losses.
- Immediate full retail access for all electricity consumers (except municipal utilities, which were left to decide if their customers would be allowed access). If customers retained the utility as their default purchasing agent, it was initially required to purchase all electricity for them from the PX at the spot market price. The legislation required the utilities to set retail rates no higher than 10 percent below 1998 tariffs for residential and small commercial customers and equal to those tariffs for industrial customers.[9] The reformers assumed that the utilities' PX wholesale acquisition costs would fall by more than 10 percent, creating enough margin for the utilities to recover most of their stranded costs by 2002 from the Competition Transition Charge.

Competition from independent electricity suppliers was expected to drive wholesale and retail rates even lower after that date. These independent suppliers or independent power brokers were also expected to capture most of the utilities' retail customers so that the utilities would have only a small exposure in their role as default providers (acquiring electricity in the wholesale market in order to sell it at fixed retail rates).

9 This legislated rate reduction, part of the compromise for political support of the California reform, was funded by having utilities issue state-guaranteed bonds in order to refinance their remaining generation assets with high (even 100 percent) debt, rather than the previous 50:50 debt-to-equity ratio.

Figure 2: ***California's Restructured Electricity Market, 1998–2000***



Note: SDGE = San Diego Gas and Electric; SCE = Southern California Edison; PG&E = Pacific Gas and Electric; munis = municipal authorities.

- A second charge on all system users to support public-purpose programs over a four-year period: $248 million for the Public Interest Energy Research Program, $540 million for the Renewable Technology Program, $912 million for the California Board for Energy Efficiency — a new entity to oversee the independent administration of energy-efficiency programs.
- Divestment — via CPUC directives — by the three large utilities of at least 50 percent of their generation assets.

Figure 2 shows the structure of the California electricity market immediately after reform. As noted, the PX wholesale spot price was mandatory for utilities, but independent generators and electricity suppliers could use the PX or contract bilaterally for any length period at fixed, indexed, or spot prices.

The California Short Circuit

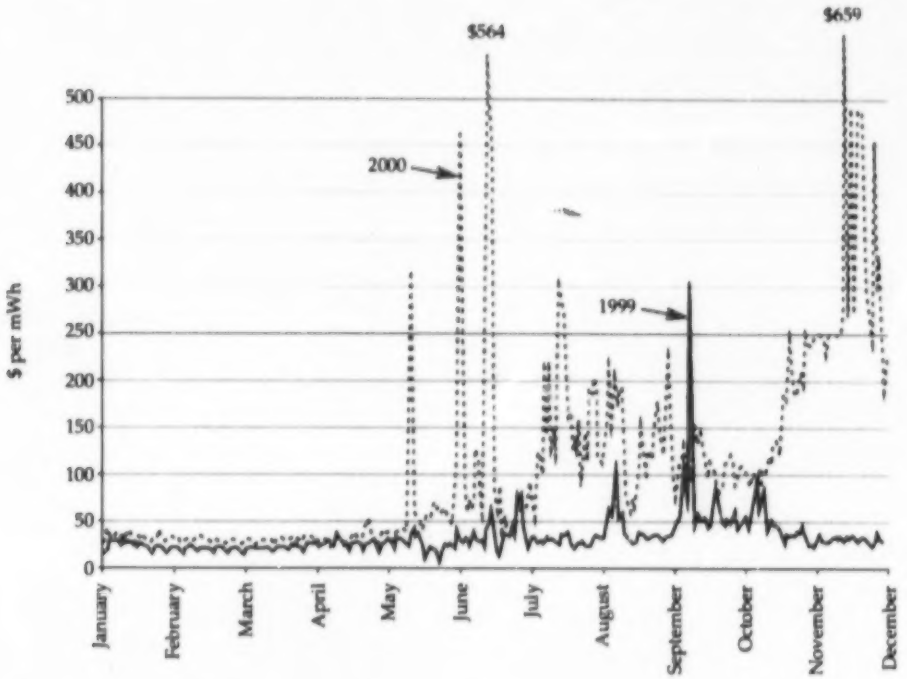
In both 1998 and 1999, California's reformed market appeared to be functioning well.[10] Wholesale prices in the PX remained low at about 3 cents per kWh, and the utilities were recovering their stranded costs quickly, hastening the date for elimination of the Competition Transition Charge. But in mid-2000, the PX wholesale price jumped dramatically and remained high through the summer. Some price spikes reached more than 50 cents per kWh, the summer price averaged 20 cents per kWh. The price started to come down in September, but by November it rose again and stayed high through the winter (see Figure 3). The high prices of late 2000 continued through the first four months of 2001, before finally returning to historical levels, where they remained through the rest of the year.

These high prices created a financial crisis for the three major utilities because their legislated retail rates were not allowed to increase in compensation for the dramatically higher wholesale acquisition costs in the PX, where all power for their default customers had to be purchased.[11] The unrecovered power costs of the three

10 However, some analysts were troubled by detailed evidence of market performance (see Earle et al. 1999; Borenstein, Bushnell, and Wolak 1999).

11 Because San Diego Gas and Electric had recovered its stranded costs in 1999, and thus eliminated the Competition Transition Charge, it was free of the legislated rate. It quickly raised its rates in order to pass through to customers its higher commodity acquisition costs; its residential rates increased from 11 to 16 cents per kWh in July 2000. Under pressure from irate customers, however,...

Figure 3: ***PX Wholesale (Day-Ahead) Spot Prices, 1999 and 2000***



Source: Personal communication from Doug Little, Powerex

utilities in 2000 were about $12 billion. This financial imbalance continued into 2001, and in April Pacific Gas and Electric filed for bankruptcy protection.

With suspicions rising that independent suppliers were making windfall profits from the high prices, the CPUC regulated a price cap in the PX — 50 cents per kWh in June 2000, reduced to 25 cents per kWh in August. Even at these prices, the ISO could not buy enough power to meet demand, so it implemented voluntary curtailments and rotating blackouts in some parts of the state in winter 2000/01. The US secretary of energy also applied a rarely used emergency authority to order independent generators to supply the ISO to avert power outages.

By the end of 2000, federal and state authorities acknowledged the need to intervene more dramatically in the dysfunctional California electricity market. The FERC terminated the PX's operating authority in January 2001 and in May began investigating the prices charged by independent suppliers, threatening retroactive adjustments if those prices exceeded cost-based levels. To fill the role of the PX, the governor of California ordered the state's Department of Water Resources to purchase power directly on behalf of the cash-strapped utilities, some of it through long-term,

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Note 11 - cont'd.

...the California legislature established a ceiling of 6.5 cents per kWh for the commodity portion of the electricity bills of residential and small commercial customers (resulting in rates capped at about 13 cents per kWh), leaving the utility in a financial crisis that was similar to, but less severe than, that facing the other two major utilities.

fixed-price contracts. Signed in haste, these contracts are estimated to be at average prices that may prove high (7 cents per kWh) over the ten-year terms of some of them and were certainly high compared with spot wholesale prices in California in the latter half of 2001. The financial liability of these contracts is about $45 billion, which again raises the specter of stranded costs and leads to serious questions about the state's near-term financial stability.

The California government is also negotiating to purchase the transmission facilities of the three major utilities at prices significantly above book value in order to compensate them for their unavoidable power acquisition losses (and to stave off legal claims against the state for causing the losses). This move is linked to a larger proposal to create a state power authority that would own the transmission system and perhaps construct power plants.

In May 2001, to begin to offset the utilities' losses, the CPUC approved rate increases of 37 to 50 percent for large commercial and industrial customers and lesser rises for residential customers. In September, the commission also suspended customers' direct access to independent electricity retailers. In October, however, it refused to approve a bond-financing agreement that would have made California ratepayers liable for the long-term power supply contracts signed by the state government.

Many observers expected the high wholesale prices and power shortages to continue through the summer of 2001, but the opposite happened. Spot prices in the summer and fall were 3 to 5 cents per kWh, with some as low as 2 cents per kWh. In other words, the prices are back to expected levels. Likewise, rotating blackouts have ceased, and voluntary curtailments have returned to normal levels. It appears that California's power crisis has abated — at least for the time being.

The Causes of the Crisis

From mid-2000 to mid-2001 California found itself in a chronically tight power market in which state and federal governments and their agencies frantically intervened.

In brief, from mid-2000 to mid-2001 California found itself in a chronically tight power market in which state and federal governments and their agencies frantically intervened to address supply shortfalls and to mitigate exorbitant wholesale electricity prices. The initial reform goals of lower prices, less government involvement, greater customer choice, and reliable supply now seem far away. The various emergency measures have, by necessity, focused on the symptoms of the California crisis. The determination of its root causes and their solution is more difficult to agree on. At least at the current level of supply and demand, the surface causes of the crisis are uncontroversial. I explain these factors below; the next section turns to the more controversial debate about the deeper causes and their possible long-term solutions.

The Obvious Factors

Five factors seem to have played an immediate role in creating the California crisis.

First, during the 1990s, California's strong economic growth drove peak electricity demand higher by about 10,000 MWs while the state's net generating capacity remained basically static. This situation was not alarming in itself; an increase in long-term imports may be optimal for economic, environmental, and

other reasons.[12] During the same period, however, peak demand dramatically outgrew capacity in the western interconnected system, which includes all of California's potential trading partners. Peak requirements rose by 26,000 MW while capacity increased by only 10,000 MW. This imbalance was tolerable during most of the decade as the region reaped the benefits of the emerging wholesale market. Without investing in new plants, producers in states and provinces throughout the interconnected region used increased trade to improve the capacity use of existing facilities. For example, the hydro-power-dominated systems of Bonneville Power Authority — primarily in Washington and Oregon — and BC Hydro often had substantial excess capacity during California's summer peak periods. By the end of the 1990s, however, most of California's neighbors also found their markets tightening, given the region-wide discontinuity between demand growth and supply expansion.

By the end of the 1990s, most of California's neighbors also found their markets tightening, given the region-wide discontinuity between demand growth and supply expansion.

Second, this long-term trend toward tighter markets was compounded by extreme weather conditions in California and its supplying regions. In California, the summer of 2000 was one of the ten hottest summers in a hundred years, causing an 8 percent jump over 1999 in peak air-conditioning load. The following winter was colder than average, leading to a greater use of electricity for space heating. At the same time, the Pacific Northwest was experiencing one of its driest periods on record, dramatically reducing the energy capability of the large hydro power facilities throughout the interconnected area.

Third, during both summer 2000 and winter 2001, plant outages, natural gas price increases, and rising pollution-permit costs combined to dramatically raise the marginal cost of in-state electricity generation. At critical times, more than 5,000 MW of in-state capacity was out of service. Scheduled outages for maintenance and nuclear refueling caused some of this downtime; the ISO lacked the authority to coordinate scheduled outages and to force units to generate at critical times.[13] High natural gas prices caused some other outages. Although prices increased throughout North America in 2000, they were as much as five times higher in California than elsewhere by December of that year. These high prices motivated some gas-fired generators to shut down rather than lose money by selling at the contracted prices for their output or at the capped prices in the PX, even though the latter were extremely high. The other critical factor was the nitrous oxides (NOx) emission-permit trading program, which affected all fossil fuel generating units in the Los Angeles area. The decline of out-of-state electricity supplies and the planned decline in available permits led to a tenfold increase in permit prices as fossil fuel electricity generators tried to outbid each other for permits in order to generate as much as possible at the lucrative PX prices. In September of 2000, this factor alone increased the supply cost from a marginal gas-fired unit by an estimated 7 to 8 cents per kWh.

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12 Some observers note the difficulty in siting new electricity generating plants in California during the 1990s, a problem undoubtedly exacerbated by the uncertainties of the reform process for investors. This observation may be true, but there is no reason a properly functioning market could not ensure sufficient supplies from jurisdictions that were willing to develop electricity generation facilities in order to provide long-term exports to California.

13 For this reason, the federal secretary of energy eventually intervened to require available generators to produce when urgently needed.

These units represented the marginal electricity generation costs in southern California and usually the entire state (Joskow 2001).[14]

Fourth, although a tight market inevitably raises prices as high-cost units are called on more frequently, it appears that the PX price spikes were accentuated by independent suppliers' exercise of market power (Sheffrin 2001). In a tight market, some suppliers may — without engaging in collusion — learn from trial and error in the bidding process whether they can increase returns by withholding some of their capacity. The initial design of the day-ahead and hour-ahead markets created a particular incentive for withholding in the former so as to bid more capacity in the higher-priced (when supplies are tight) hour-ahead market. Such a practice drives prices even higher. One observer (Joskow 2001) says that about a third of the wholesale price in the period June to September 2000 can be attributed to the exercise of market power. Suspicion that prices in the PX were being manipulated in this way was a key factor in the FERC decision to suspend its operation in January 2001.

Fifth, the rising wholesale prices could not lead to rising retail prices, which were still controlled by the state legislature and the CPUC. Under public pressure, both of these agencies resisted increasing retail rates to reflect the escalating wholesale acquisition costs. As a consequence, there was none of the short-term demand response that would normally help a tight commodity market return to equilibrium.

In concert, these five factors created short-run supply and demand curves that were both close to vertical (virtually price inelastic, in the words of economists). In such circumstances, price can skyrocket, and it did. The effect was regional, as wholesale prices throughout the western region rose in concert with California's.

The diffusion of responsibility for the reformed electricity sector complicated efforts to address even surface manifestations of the crisis.

The diffusion of responsibility for the reformed electricity sector complicated efforts to address even these surface manifestations of the crisis (FERC 2000; CPUC 2000). Just as the initial market restructuring required negotiation and cooperation between several entities, dealing with the crisis presented the same challenge but over the compressed time scale of an emergency.[15] Although the FERC had regulatory authority over the PX and the ISO, it had allowed California to take the lead in designing these two components of the reformed state electricity system. With the PX malfunctioning and the ISO lacking sufficient authority to ensure reliability, confusion arose as to whether federal or state authorities should intervene.

By mid-2001, these authorities were beginning to achieve greater cooperation and coordination. The fall of prices in summer 2001 and their apparent stability since then can be attributed in part to the preventative actions of the main public agencies; weather and normal market responses have also played key roles. Higher retail rates, widespread awareness of the crisis, and intensified electricity-efficiency programs have motivated Californians to conserve electricity and to shift their demand to off-peak periods. The summer of 2001 was considerably cooler than that of 2000. Correcting for these temperature differences, peak demand was also lower because of efficiency and load-shifting efforts. Also, three new power plants

14 Northern and southern California prices often differ when the major north-south transmission intertie is congested.

15 Political commentators suggest that this problem was complicated by differing political and regional interests as the newly elected Republican federal government sparred with California's Democratic state government.

began operating in California, and the outages of existing plants at key times were dramatically reduced, an improvement explained by lower natural gas prices, the removal of electricity generators from the NOx-permit trading program, and better coordination of maintenance scheduling. Finally, the availability of out-of-state supplies increased as utilities and independent power suppliers in neighboring jurisdictions found ways of freeing capacity and energy in order to benefit from possible high prices in California. For example, Bonneville Power Authority developed revenue-sharing agreements that would lead to voluntary curtailment from some of its major industrial customers in the Northwest at times of high California prices.

Cautions for Reformers

The fact that California's prices have subsided does little, however, to ease concerns of those in other jurisdictions who are contemplating electricity market reform. The state's electricity bill during the one-year crisis was enormous and has not yet been recovered from consumers, taxpayers, and perhaps suppliers (some of whose profits are under FERC investigation). New long-term contracts signed in haste by the state government may saddle future consumers and taxpayers with an additional unnecessary liability of several billion dollars if the agreements turn out to be above market value. Retail prices are now much higher than when the restructuring process began in 1996 and have little prospect for decline in the coming years. What assurance is there that this situation would not happen elsewhere?

California has, at great cost to itself, provided other jurisdictions with a free demonstration of the risks of electricity reform.

To put the point another way, California has, at great cost to itself, provided other jurisdictions with a free demonstration of the risks of electricity reform. It now appears that the probability of something going wrong is greater than many reformers assumed. And the losses that result can be dramatic. Recent studies show that the losses from power outages in the United States prior to California's forced rolling blackout were already in the tens of billions (EPRI 2001).

What can we learn from this experience? To this end, three questions are salient.

1. Why was there insufficient investment in new capacity in California during the 1990s such that tight market conditions developed?
2. Given the requirement to balance supply and demand instantaneously at all points on the electricity grid, how difficult will it be to prevent the exercise of market power during tight conditions in electricity markets?
3. Given the essential service character of electricity for most customers, what is the potential for demand response to help reduce spot market price volatility?

Reform enthusiasts argue that Californian reformers made mistakes in all three areas covered by these questions and that they could have prevented the crisis had they emphasized an even greater role for unfettered market forces on both the supply and the demand sides. Reform skeptics suggest that difficulties in these areas will plague any attempt to create competitive electricity markets, meaning that Californians will soon have company in their misery.

I find myself between these two positions. I agree that the potential social benefits of competitive electricity markets are great and should be pursued in any

jurisdiction. The alternative of leaving major investment decisions to central planners, with the costs of mistakes borne by all, is not a good way to address pervasive investment risk in the electricity sector. Moreover, improving the efficiency of electricity systems offers substantial benefits and competitive markets provide the incentives for realizing them, as we have already witnessed through the development of interjurisdictional trade at the wholesale level. At the same time, I believe that the unique characteristics of electricity as a commodity are so significant that the designers of markets for it must be much more cautious than they have been. They must be much more willing to incur extra costs in system design and operation in order to ensure that supply investment sustains the capacity reserve margins needed for most customers' high standards of reliability and price stability.

The unique characteristics of electricity as a commodity are so significant that the designers of markets for it must be much more cautious than they have been.

In contrast, California's reformers were at best remiss and at worst arrogant in this regard, and several other reformed and reforming jurisdictions — sometimes sounding quite smug when discussing California's misfortune — may be equally at risk. To address my three questions about the California experience, I begin by explaining two key ways in which electricity is a special commodity requiring specific market design conditions and market interventions. I then turn to the three specific questions.

Electricity is a special commodity in that supply and demand must be balanced at all times throughout the grid, and the path of electron flow cannot be guaranteed. If a supplier fails to meet a contractual obligation to deliver power into the grid, all other grid users are immediately affected. Therefore, centralized and independent control of system operation is required to keep track of unmet obligations in real time, compensate for them immediately, and thereby ensure system stability for the benefit of all users. Centralized system operation should develop mechanisms to ensure that resources are dispatched on the basis of the lowest short-run marginal cost (*merit dispatch*) and to help participants establish mutually beneficial contracting arrangements that facilitate this objective.

Many things can go wrong in creating mechanisms for system operation. Over the past two decades, analysts have produced a large literature on the pros and cons of alternative mechanisms in terms of their ability to best satisfy multiple objectives. Of particular concern is the tradeoff among:

- achieving merit dispatch based on short-run marginal costs at all points on the grid;
- providing the correct long-run price signals to stimulate sufficient new capacity investment;
- minimizing excess profits to electricity providers;
- meeting high reliability standards; and
- incorporating demand response when it is the lowest-cost means of balancing the market.

If market reformers are prudent, they would overdesign the system — up to some socially acceptable insurance cost — to ensure robustness under a wide range of extreme conditions, especially given the large uncertainties at this experimental phase of electricity market reform. Although operators must strive for dispatch based on short-run marginal costs, they must not allow pursuit of this goal to discourage the investment needed for an ongoing and substantial reserve margin,

for this latter condition is a necessary precursor for attaining other objectives, such as high reliability and minimal excess profits. Maximizing the potential for cost-effective demand response, especially via demand shifts to off-peak periods, could further contribute to these objectives.

The second way in which electricity is special is that it provides an essential service. In the modern information age, the value of uninterrupted electricity supply has continually increased to today's extremely high standards for reliability. At the same time, although electricity is a final consumption commodity for residential and small commercial customers — one for which they are directly billed every two months or so — most of these consumers are unlikely ever to interest themselves in or appreciate the kind of volatility that is a norm in other commodity markets, such as lumber, wheat, and copper. Yet, a competitive electricity market, left to its own, would likely exhibit the same cyclical price and investment pattern of these other commodity markets: the market tightens; prices shoot up and some people have trouble getting supply; high prices stimulate supply investment and demand reduction; as supply increases relative to demand, prices fall; and then the cycle repeats itself.

Problems can occur if electricity reforms are designed by market enthusiasts who believe that everyone is, or should be, as excited as they are about the intricacies of competitive markets.

Problems can occur if electricity reforms are designed by market enthusiasts who believe that everyone is, or should be, as excited as they are about the intricacies of competitive markets. In the real world, industry and large commercial customers may be interested, but almost all householders simply want to pay a stable, manageable rate for a reliable supply that they never have to think about, even if that security costs a reasonable premium. This characteristic of electricity puts the onus on market reformers to include mechanisms that ensure a highly reliable service to almost all consumers.

Thus, cautious market reformers should reduce the likelihood of extreme supply and demand imbalances by including an extra incentive, at a reasonable cost, that compensates risk-taking investors for the chance that their units may run infrequently during times of excess supply. Pricing and contracting mechanisms can also ensure average retail price stability during times of volatile wholesale spot markets, without creating a financial imbalance. Providing opportunities and rewards for those consumers — usually, but not exclusively industrial customers — who can and are willing to reduce demand in response to price signals would further improve the prospects for a stable market.

In hindsight, the designers of the California system, including the FERC, should have been much more cautious and assessed the robustness of their market design under alternative conditions, especially with regard to the implications of the unique characteristics of electricity. Instead, the California reformers assumed that the right amount of investment would happen at the right time simply because they had opened the market. They assumed that prices could go only down, so they legislated fixed retail rates and did not allow distribution utilities to hedge the wholesale spot market rates. They assumed that independent generators could not manipulate the spot market (although they worried about the former utilities), so they neglected to establish adequate safeguards. They assumed that price signals alone would enable the system operator to ensure adequate hourly supply, so they did not give that operator ironclad authority to secure backup supplies. They assumed that California's spot market would continue to attract sufficient out-of-

state supply, so they did not encourage the distribution utilities to sign long-term contracts with external suppliers or with anyone else. They assumed that customers would eagerly engage in retail shopping, so they did not plan for the contingency of most retaining the utilities as their default suppliers.

What happened was certainly not what the system designers expected. Investment did not occur when needed, and the market tightened with no potential for short-run supply response. Wholesale prices skyrocketed well above the marginal costs of production, suggesting substantial profit taking. Moreover, retail demand did not respond to ease the situation — a not-unexpected result, given that retail prices were not allowed to change. I now examine each of my earlier questions in turn.

1. *Why was there insufficient investment in new capacity in California in the 1990s?*

Some analysts argue that the process of designing and implementing a new market created too much uncertainty for investors but that as this uncertainty diminishes in the future independent investors will ensure a continuous excess capacity for the California system, leading to price stability and supply reliability. I am not convinced. I do not see why the competitive electricity market will differ from the cyclical patterns of investment, market imbalance, and price volatility exhibited by other commodity markets.

If reformers value a substantial and continuous reserve margin in competitive electricity markets, they must design the system so that this situation will occur.

If reformers value a substantial and continuous reserve margin in competitive electricity markets, they must design the system so that this situation will occur. England has had over a decade of relative price stability and a high reserve margin, but its 1990 reform included a central pricing mechanism that guaranteed a capacity payment for available generators, even when not dispatched. The amount of the payment increased as the reserve margin decreased. Observers suggest that this payment motivated generators to keep little-used plants available to the market, thereby ensuring a stable and sufficient capacity reserve (Green 1999). In a sense, they had an incentive to sustain excess capacity, reflecting the high value to consumers of a substantial reserve margin in the system, which is what monopoly utilities tried to provide in the past. Such a design in a reformed North American market would combine the benefits of competitive markets with the value to consumers of a highly reliable system, given the unique physical characteristics of electricity and its critical role in modern society.

Ironically, England has eliminated the capacity payment in its latest reforms, but the events in California have now raised concern with this decision ("Beyond the Pool," *The Economist*, March 1, 2001). Some other jurisdictions with relative price stability, such as the Scandinavian countries and Australia, have had both continued involvement of public ownership and the benefits of expanded wholesale trading opportunities coincident with market reform, making it difficult to conclude with confidence that they are fully insulated from a California-type event. Although only time will tell the benefits and costs of a capacity payment, a cautious reformer should be willing to incorporate some similar mechanism for the early years of market reform, perhaps in coordination with neighboring jurisdictions. If the market does tighten for some reason, the second question arises.

2. *In tight electricity markets, how difficult will it be to prevent the kind of exercise of market power as occurred in California?*

An integrated electricity network has common-property attributes in that transaction imbalances can affect third parties. Although such interdependence is a frequent attribute of networks, the electricity network must be kept almost exactly in balance at all times.[16] Whoever is responsible for ensuring this balance depends on suppliers' responding as price rises to reflect market tightness. But under very tight conditions, suppliers may garner market power simply because of the extremely short time frame for ensuring the supply-demand balance. Also, transmission constraints create local situations in which only a few suppliers are available to respond to higher price signals. The opportunities for short-term economic withholding of supply can be substantial.

If reformers agree that the electricity market is unique in tilting the balance of opportunity in favor of those who might gain from gaming the market, then they need to incorporate preventative mechanisms in their market wiring diagram.

If reformers agree that the electricity market is unique in tilting the balance of opportunity in favor of those who might gain from gaming the market, then they need to incorporate preventative mechanisms in their market wiring diagram. In the aftermath of the California crisis, the FERC announced, in May 2001, a price-mitigation plan, and both the California and New York ISOs announced plans to investigate and fine generators that sell power substantially above cost.

This policy may, however, be a double-edged sword, given that the definition of "excess profit" is controversial. If the FERC forces generators to return all earnings in excess of short-run operating costs, suppliers may have insufficient incentive; they need prices that, on average, recover both operating costs and investment. Market enthusiasts argue that high returns are occasionally necessary to attract rent-seeking investment that eventually culminates in sufficient and even excess capacity. They say that the best solution is to design a system that maximizes the opportunities for quick entrance — both by constructing in-state capacity and by rapidly expanding transmission interconnection with neighboring jurisdictions.

I agree that these policies should help. But for the same reasons set out in my response to the first question, I believe that the best solution is to create the conditions for a significant, ongoing reserve margin, even at some cost. The other hope is the existence of low-cost but unexploited opportunities to foster a quick and significant demand response to higher prices. This leads to the third question.

3. *What is the potential for demand response to help stabilize electricity markets in California and elsewhere?*

California's utilities are now hastily developing market-based pricing programs that would allow consumers to benefit themselves and the system by modulating their demand in response to fluctuations in the wholesale price. Such real-time pricing requires the installation of electronic interval meters and the development of a time-of-use tariff in which the variable part of a customer's bill adjusts in proportion to price changes in the wholesale spot market. Obvious candidates for

16 Even the natural gas network, which is otherwise quite similar, has a greater ability to adjust in real time because it can tolerate substantial changes in pipeline pressure. An electricity grid can withstand only much smaller percentage imbalances.

real-time pricing are industrial and large commercial customers, but technological advances and economies of scale in meter production may eventually allow its application to smaller customers.[17] Recent research indicates that in tight markets a relatively small demand response can dramatically reduce market price. A simulation by the Electric Power Research Institute suggests that during California's tight market a 2.5 percent drop in peak demand would have reduced wholesale prices by as much as 24 percent (Faruqui et al. 2001). As a precautionary measure, market-based pricing programs could be in place well before launching market restructuring. Even a vertically integrated utility can achieve them simply by establishing tariffs that unbundle delivery charges (transmission and distribution) from the commodity charge and tying the latter to the wholesale prices from interjurisdictional trading. Many monopoly utilities have offered such tariffs in the past.

For many small and some large customers, electricity is not a commodity to which they want to pay much attention. Rather, it is a necessity for which they desire extremely high reliability, and they are willing to pay a premium to ensure it. Reformers need to design systems that ensure stable reserve margins and minimize price volatility for these consumers. Of course, the rates they pay should reflect the extra system costs of ensuring surplus capacity and contracting to ensure long-run price stability. At the same time, other customers should be given the opportunity to benefit the system and themselves by responding to price signals.

Reform Experiences in Canada

Authority over the electricity system is more decentralized in Canada than in the United States.

Authority over the electricity system is more decentralized in Canada than in the United States, so there is no Canadian equivalent of the *National Energy Policy Act of 1992* or the FERC Orders 888 and 889 of 1996 to signal federal support for electricity market reform (National Energy Board 2001).[18] Unlike the FERC, the National Energy Board of Canada does not have jurisdiction over wholesale electricity trade unless it is interprovincial or international.[19] The provinces have jurisdiction over energy, and most of them long ago created provincially owned electricity monopolies. The motive was in part to subsidize extension of the grid to a dispersed population and in part to develop the bountiful hydro power resources of several regions (Jaccard 1994). Hydro power, which accounts for 60 percent of electricity supply in Canada in comparison to only 7 percent in the United States, is often associated with public ownership because of its many social and environmental impacts.[20]

17 During 2001, California was installing hourly meters for all customers with peak demands of more than 200 kW.

18 My description of Canadian jurisdictions is based in part on information contained in government websites: notably, the National Energy Board, www.neb.gc.ca/pubs; Alberta Energy, www.energy.gov.ab.ca/electric/index.html; and Ontario Ministry of Energy, Science and Technology, www.est.gov.on.ca/english/en/en_elec.html. Price amounts here, in contrast to those in the previous sections, are denominated in current Canadian dollars.

19 The National Energy Board regulates the construction and operation, including tariffs, of interprovincial and international pipelines and transmission lines.

20 Major hydro power developments in the United States (Bonneville Power Authority and Tennessee Valley Authority) are federally owned, and countries with predominantly hydropower systems, such as Norway, New Zealand, and Brazil, remain dominated by public ownership even after substantial electricity sector reforms.

The importance of provincially owned hydro power resources explains in part why electricity market reform has been slower in Canada than in the United States.

The importance of provincially owned hydro power resources explains in part why electricity market reform has been slower in Canada than in the United States (see Table 1). Another key factor is that most Canadian jurisdictions have fairly low electricity prices. They are a legacy of the country's hydro power endowment and low-cost coal deposits and of provincially owned utilities that have very low costs of capital because of high debt-to-equity ratios with the cost of borrowing lowered by provincial securitization and because of their exemption from federal income tax.

Two Canadian provinces have pursued electricity market reform for ideological and cost reasons. Alberta has a conservative tradition of minimizing the role of central planners and favoring markets and private ownership where possible; before the 1990s, it was the only province dominated by privately owned utilities. Indeed, Alberta stands out as a region interested in electricity market reform despite having some of the lowest electricity costs in North America. In contrast, Ontario's electricity sector reform had been motivated primarily by high costs, although ideology also played a role. From the time its Progressive Conservative government reached power in 1995, it has sought to reform the electric sector in order to reduce government involvement and lower prices through competition.

Alberta

Alberta's reform, like California's, started relatively smoothly, but then it too entered a challenging phase, albeit not one approaching the crisis proportions of California's. Before the reforms, the province's electricity sector was dominated by three vertically integrated utilities, two of them investor-owned (TransAlta and Alberta Power) and one municipally owned (Edmonton Power).[21] Vertical deintegration proved a fairly easy step because of the earlier creation of a power-pooling mechanism. In 1982, to ensure uniform wholesale rates throughout the province, the Alberta government had established an agency to purchase electricity from all generating units at regulated, cost-of-service rates and then resell it to the distribution arms of the utilities at an averaged, uniform rate.

In its *Electric Utilities Act* of 1995, the Alberta government required the utilities to relinquish control of their transmission facilities to an independent transmission administrator (much like an ISO) and created a mandatory Power Pool that began operation in 1996 (Alberta Resource Development 2000). To preserve the benefit of low-cost generation for domestic customers, the government legislated long-term, fixed-price contracts between the separate generation and distribution divisions of the utilities.[22] These agreements allowed average retail prices to remain at stable, low levels regardless of the Power Pool price. The latter functioned as a typical spot market, determining the trading price and dispatch merit order for wholesale market balancing in the short term, while providing signals of market tightening for long-term supply investment decisions.

The Alberta government implemented further market reform in 2000 by forcing the utilities to divest themselves of the production rights from their generation assets.

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21 Other cities in Alberta have municipal utilities as well.

22 These contracts, referred to as *legislated hedges*, had some provision for price adjustments to reflect an unavoidable change in generation costs, such as an unforeseen environmental regulation.

Table 1: ***Provincial Electricity Sectors***

	Capacity[a]	Energy Types for Generation[b]	Residential Prices	Primary Ownership	Market Structure
	(MW)	*(%)*	*(¢/kWh)*		
British Columbia	13,600	natural gas, 5; hydro, 89; other, 5	6.1	provincial	vertically integrated monopoly
Alberta	8,900	coal, 78; natural gas, 16; hydro, 4; other, 2	11.8	private	retail competition / vertically deintegrated with ISO
Saskatchewan	3,100	coal, 69; natural gas, 9; hydro, 22; other, 1	8.6	provincial	vertically integrated monopoly
Manitoba	5,100	coal, 3; hydro, 97	5.9	provincial	vertically integrated monopoly
Ontario	29,500	coal, 24; Oil, 1%; natural gas, 7; nuclear, 42; hydro, 24%; other, 1	9.3	provincial	retail competition (pending) / vertically deintegrated with ISO
Quebec	35,100	oil, 2; nuclear, 2; hydro, 96	6.0	provincial	wholesale competition with commission determination / still vertically integrated
New Brunswick	4,600	coal, 32; oil, 29; nuclear, 20; hydro, 15; other, 4	8.0	provincial	vertically integrated monopoly
Nova Scotia	2,300	coal, 66; oil, 23; hydro, 9; other, 2	9.4	private	vertically integrated monopoly
Prince Edward Island	100	oil, 100	—	private	vertically integrated monopoly
Newfoundland	7,300	oil, 3; hydro, 97	8.3	provincial	vertically integrated monopoly
Territories[c]	400	oil, 37; natural gas, 10; hydro, 53	—	provincial	vertically integrated monopoly

[a] Installed capacity includes both utility and industrial establishments, 1998.

[b] Cells that do not add to 100 percent reflect rounding errors.

[c] Yukon, Northwest Territories, and Nunavut.

Sources: Capacity and energy types for generation, 1998: Canadian Electricity Association 2000. Residential prices, July 2001: BC Hydro. Calculated based on a monthly bill of 1,000 kWh. Rates are representative of the following Canadian cities: Vancouver, Calgary, Regina, Winnipeg, Toronto, Montreal, Saint John, Halifax, St. John's.

The method used was an auction of power purchase agreements, which specified fixed monthly payments from the new owners of the generation rights to the owners of the assets (to cover marginal generation costs and unrecovered capital costs). Now, the owners of the generation rights must bid all of their power into the Power Pool but can sign long-term hedging contracts with customers.

The designers of the reform had assumed that the auction would generate a large surplus representing the difference, over the economic lives of the generating plants, between their low cost of production and rising Power Pool prices as the market tightened. Instead, the auction in mid-2000 attracted few bidders, and the bid prices were far below government expectations; the total revenue of the initial auction was just over $1 billion (Daniel, Doucet, and Plourde 2001).

The timing could not have been worse. In the year before the auction, the average Power Pool price was less than 5 cents per kWh, and it had been even

lower in 1998. But in summer 2000, the average wholesale price rose quickly to 20 cents per kWh and remained in this range to the end of the year. A crude analysis shows that, at prices above 8 cents per kWh, most purchasers of generation rights would see their initial investment paid off within a year. Thus, these investors could earn substantial profits for the remaining life of the power purchase agreements, some of which last for close to 20 years. This money would have remained with consumers had the long-term contracts not been replaced with the auctioned power purchase agreements.[23]

Several factors contributed to the sudden rise in the Power Pool price in the period immediately after the auction. First, because natural gas units are the marginal producers in Alberta, the Power Pool price was influenced by the rising natural gas price throughout North America, which was especially pronounced in the western regions affected by California's increased natural gas demand. Second, although Alberta is not directly connected to the United States, its 400 MW link to British Columbia provides an opportunity for BC Hydro to purchase power from Alberta — bidding up prices if necessary — in order to sell it into the lucrative regional market in and around California.[24] Third, analysts have raised questions about whether the Alberta spot price, like that in California, may have been increased by the bidding strategies of influential suppliers (Daniel, Doucet, and Plourde, 2001).

Analysts have raised questions about whether the Alberta spot price, like that in California, may have been increased by the bidding strategies of influential suppliers.

On the demand side of the market, the initial plans were for all customers to receive retail access in January 2001. As prices skyrocketed, however, Alberta put these plans on hold and capped retail rates. Unlike California, it has been able to do this without creating a financial crisis because the rate cap is tied to the results of a second auction that sold the generating rights (only for 2001–03) to plants not covered in the first auction, with the requirement that power be supplied at the wholesale price of 11 cents per kWh. The combined revenues of the two auctions totaled $2 billion, which the government rebates monthly to customers at 4 cents per kWh. Within two years, the auction revenues should be exhausted. When distribution and other costs are added to the wholesale price and the rebate, Alberta's net residential rates for 2001 were about 12 cents per kWh, giving the province the dubious distinction of jumping from one of the lowest to the highest electricity rates in the country.

Where do all these events leave Alberta today? It has still not achieved the competitive market that planners envisioned. Rather, it has significant market intervention by regulators and government. But the government remains hopeful that significant expansion plans for generation capacity will, within a few years, create enough competition and an adequate reserve margin to drive retail prices back down to the stable, low levels that were anticipated (Nikiforuk 2001).

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23 Some consolation may lie in the fact that major purchasers of the generation rights were subsidiaries of the municipal utilities of Calgary and Edmonton. Thus, much of the high return is a transfer within the province, some of it possibly returning to electricity consumers in these two cities.

24 In November 2000, Alberta responded to the resulting pressure on its prices by changing the Power Pool pricing mechanism so that exports to British Columbia could still be bid and dispatched in merit order but would not set the Power Pool price. After this change, the Power Pool price dropped to an average of 11 cents per kWh through the first half of 2001.

Ontario

Ontario is the only other Canadian jurisdiction advancing quickly toward the competitive model. The *Energy Competition Act* (1998), which included both the *Electricity Act* (replacing the *Power Corporation Act*) and a new *Ontario Energy Board Act*, provide the framework for reform (Ontario 1997). Vertical deintegration has already occurred with the breakup of publicly owned Ontario Hydro into five successor companies.

One of them is Ontario Power Generation, which now holds all of the generation assets but intends to divest most of them to the private sector over time. Another is Hydro One, which owns the transmission grid and the parts of the distribution system not served by municipal utilities; it is acquiring some of the distribution assets formerly owned and operated by more than 300 municipal utilities. Through municipal amalgamations, mergers, and acquisitions by Hydro One, the number of municipal utilities in Ontario is now down to about 90. As in other jurisdictions, an independent operator will manage the transmission system and run a spot market.

The market was to open to retail competition in November 2000, but the Ontario government has moved the date to May 2002. A customer charge of 0.7 cents per kWh will pay off the residual stranded debt of the former Ontario Hydro, much of which is attributable to nuclear power units. A price-rebate mechanism will protect consumers from the exercise of market power while Ontario Power Generation divests itself of generating units. During the four years following market opening, Ontario Power Generation must decrease to 35 percent or less its market share of *price-setting plants* (including interties), which are defined as anything other than nuclear and hydroelectric plants. Also, during the ten years following market opening, Ontario Power Generation must reduce its share of in-province generation capacity from the current 90 percent to 35 percent or less. Until it reaches these targets, it must rebate to all Ontario consumers a portion of its revenues when annual average revenues exceed 3.8 cents per kWh.

Ontario's restructuring design has not yet been tested. It is noteworthy that it does not contain an explicit mechanism to ensure a substantial reserve margin (although the transmission operator has the authority to establish such a mechanism if one is needed in the future). Ontario also lacks an extensive set of real-time pricing tariffs, although the market design incorporates dispatchable load (principally industrial load), which can be curtailed during high-price periods. Officials maintain that Ontario is not vulnerable to the problems of California and Alberta because it has a diverse production mix, less reliance on natural gas, and 17 interconnections with neighboring jurisdictions (Holloway 2001). It remains to be seen if this situation will offer sufficient protection.

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Other Canadian Jurisdictions

Most other Canadian jurisdictions have opened their transmission networks to third-party access; the usual motive has been simply to meet the minimal reciprocity requirements of the FERC for transmitting electricity through other jurisdictions in order to reach US markets. Independent power producers find few

domestic opportunities when the vertically integrated monopoly is virtually the only potential purchaser of electricity.

Other than Alberta and Ontario, Quebec has gone furthest toward a competitive generation market. Although Hydro-Québec is not fully vertically deintegrated, the company is divided into distinct generation, transmission, and distribution divisions and a law in June 2000 (Bill 116) established a competitive relationship between the company's generation division and independent power producers. The law fixes a quantity and price (165 TWh per year at 2.79 cents per kWh) for Hydro-Québec's existing hydro power resources as a continuous supply obligation from the generation division to the distribution division of the company, thereby providing domestic customers with an indefinite entitlement to the province's low-cost hydro power resources. For supplies to meet load growth, the generation division must now compete with independent power producers in placing supply offers before the distribution division. The latter uses an integrated resource planning process, under the regulation of the independent utilities commission, in determining its resource portfolio for new supply. This industry structure is generally referred to as *wholesale competition*, although purists would argue that true wholesale competition exists only when the distribution utility severs all corporate links to the owners of generation units.

Other Canadian jurisdictions are in a wait-and-see mode. New Brunswick and Nova Scotia are perhaps the closest to taking reform action of some sort. Each has a Progressive Conservative government that is looking for ways to diversify the current monopoly situation without yet embracing full market restructuring.

Suggestions for Canadian Reformers

The recent difficulties of California and, closer to home, Alberta send a clear warning about the perils of electricity market reform, especially about the assumption that electricity can be treated identically to other commodities. Should reform therefore be abandoned? Should Canadian jurisdictions simply retain their publicly and privately owned monopolies on a business-as-usual path?

The answer is no. The risks of the monopoly model are great, though not always obvious at the time investment decisions are made. The electricity sector today is as uncertain as ever, and big misinvestments will occur. The monopoly model saddles all customers (or taxpayers) with these risks, instead of allowing private investors to play a risk-taking role. Ontario Hydro's experience with nuclear power is a clear illustration of this limitation of the monopoly model. Also, competitive markets improve operating efficiency. The expansion of wholesale electricity trading throughout North America over the past decade has shown the enormous efficiency gains that competition can bring.

Blind faith in markets is just as dangerous as blind faith in central planning.

Blind faith in markets is, however, just as dangerous as blind faith in central planning. Any reform design that seeks benefits from the long-run cost efficiencies of competition must address the special characteristics of electricity. These characteristics bring large financial risks, as California has so emphatically demonstrated. Because electricity supply and demand must be kept in physical balance at all times and because electricity is so essential to modern society, a competitive market is especially vulnerable to an exaggeration of the price and

investment oscillations that are common to all commodity markets. These possibilities, in turn, enhance the potential for suppliers to detect and exploit temporary conditions of market power, which can further accentuate market volatility.

In the face of this challenge, what are my specific suggestions for Canadian reformers? I begin by summarizing my answers to the three questions about California's calamity.

1. Until we have a great deal of experience to the contrary, we should assume that, in the absence of specific mechanisms, competitive electricity markets will experience a cyclical pattern of overinvestment and underinvestment, with the latter leading to periods of inadequate reserve margins and diminished reliability.
2. We should assume that, in tight market conditions, suppliers will be able to influence the spot market price.
3. We should incorporate mechanisms that enable demand-side response that can cost-effectively dampen spot market price volatility while recognizing that any mechanism will be insufficient to eliminate all such volatility.

Therefore, as part of the cautious implementation of competitive generation markets, Canadian reformers should develop strategies that focus on two goals: (a) to limit the potential for extreme price volatility and price manipulation in spot markets, including any associated reduction in system reliability; and (b) to reduce the influence of short-run market price volatility on average retail rates, while ensuring that price signals are transmitted to consumers who can respond in ways that improve system efficiency.

Real-time pricing should be widely available (by tariffs or direct retail access) to as many consumers as economically possible.

The first strategy requires mechanisms that foster a rapid response from both the demand and the supply side to short-term price signals. From the demand side, real-time pricing should be widely available (by tariffs or direct retail access) to as many consumers as economically possible. Large customers can acquire interval meters, but various time-of-use devices and associated tariff options can increasingly be cost effective for smaller customers too. The pursuit of such expanded opportunities should be a key component of electricity market reform. From the supply side, the response time to suddenly high prices is delayed if that response entails new generation or transmission investments. For this reason, prudent reforming jurisdictions should be willing to pay a premium for assurance of an adequate reserve margin even during extreme situations.[25] The combination of weather-related demand increases, sudden plant outages, high natural gas prices, insufficient domestic investment, and reduction of external supply that occurred in California could occur elsewhere. But the consequences could be much smaller if the reform had included, from the outset, an extra premium to spot market prices that compensates generators for keeping an adequate reserve margin in the system. In California, such a premium would have motivated new supply investments at an earlier time. As in England's previous system, the size of the payment should be

25 Monopoly utilities effectively recognized the high consumer value in reliability when they tended to build-in excess capacity in their plans. With a competitive market, this high value for reliability and price stability still exists. Indeed, the competitive market, with its diversity of customer options, provides an opportunity to better match the performance of the system to this value.

linked to the size of the reserve margin: the smaller the reserve margin, the higher the probability of loss of load and the greater the capacity payment. Alberta and Ontario could take a more cautious approach with respect to this issue, both in terms of their pricing options for all customers and their financial support now for an adequate reserve margin.

The second strategy has some overlap with the first in its emphasis on rate design and pricing options for all customers, in this case to minimize the impact of spot market price signals on average retail rates. Economic efficiency does not require that average prices move in lock step with marginal prices in spot markets. Long-term, fixed-price contracts can cover a large fraction of consumer demand while still enabling short-run marginal cost signals to be provided to all consumers. Large customers with variable load or curtailment potential have an incentive to develop a supply portfolio that enables them to respond to short-run price fluctuations while stabilizing their average power costs through direct long-term supply contracts or price hedging contracts. Small customers could have similar options through their retailers or through the tariff options of their distribution utilities.[26] In California, this approach would have prevented a short-run supply shortfall — with its real but not huge costs — from becoming a multibillion dollar hemorrhage.

A related issue for many Canadian jurisdictions is that the overall effect on average prices from retaining the advantages of low-cost generation resources for domestic consumers need not impinge on economic efficiency goals. For example, Quebec's entitling of its domestic consumers to enjoyment of hydro power resources at a fixed, low rate of 2.79 cents per kWh can be combined with a competitive market in which accurate short-run and long-run price signals are provided to consumers and investors by means of the retail access and tariff mechanisms outlined above. Ironically, this situation was the one that Alberta created with its contracts between generators and distribution utilities in the 1996–2000 period. These contracts tied average retail rates to the province's low-cost coal plants. The wholesale spot market, in concert with long-term supply contracts with distribution utilities and large customers (and perhaps a capacity premium mechanism as outlined above), could have provided the necessary signals to motivate new capacity investment. This market could also have provided — again through large customer retail access or real-time pricing tariffs — the signals for efficient demand-side responses. Instead, Alberta elected to auction off this low-cost benefit in the hopes that the returns would flow back directly to consumers and taxpayers and that wholesale and retail prices would remain low. For the many low-cost Canadian jurisdictions, Alberta's experience provides a critical lesson: there is no need to surrender low-cost generation endowments as part of market reform. The hydro power endowments of British Columbia, Manitoba, and Quebec (and perhaps the thermal endowment of Saskatchewan) are likely to remain relatively inexpensive sources of power under most scenarios of technological change, environmental constraints, and market dynamics.[27]

For the many low-cost Canadian jurisdictions, Alberta's experience provides a critical lesson: there is no need to surrender low-cost generation endowments as part of market reform.

26 The general term for utility tariffs that provide this option is *nonlinear pricing* (Wilson 1992).

27 For a description of how retention of a low-cost endowment can be consistent with competitive generation markets, see Jaccard (2001).

Canadians should not turn their backs on the benefits of electricity market reform.

Canadians should not turn their backs on the benefits of electricity market reform. If it is to succeed, however, such reform should proceed in a prudent, cautious manner that recognizes the special characteristics of electricity as a commodity and that preserves some of the financial advantages that Canadian electricity consumers already enjoy from their resource endowment. The risks of staying with the monopoly model are high. But the designers of market reform must understand that the risks on the other side can also be very large if substantial precautions are not taken. That is California's lesson.

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